GREAT RIVER
ENERGY®

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VIA E-MAIL
AND U.S. MAIL

July 15, 2011

Received
Air Quality
JUL 2011

Mr. Terry L. O'Clair
Director, Division of Air Quality
North Dakota Department of Health
Gold Seal Center
918 E. Divide, 2nd Floor
Bismarck, ND 58501-1947

RE: BART Revisions and Proposed NOx Testing

Dear Mr. O'Clair:

In response to recent correspondence from EPA, Great River Energy (GRE) has reevaluated the Coal Creek Station (CCS) NOx technology options, as originally presented in the BART Emission Control Cost Analysis Table A-1a. After making minor corrections to some erroneous calculations and updates to the capital costs, the analysis shows that Selective Non-Catalytic Reduction (SNCR) technology is not cost effective.

In addition, Great River Energy is committing to additional NOx optimization studies to better improve upon emissions reductions. It is our firm position that SNCR should not be required, based upon cost effectiveness thresholds as well as the relatively minor deciview improvements associated with the emission controls. Finally, Great River Energy has strong reservations about the feasibility of the ash mitigation technology, which will negatively impact ash sales. Given the limited timeframe to respond to recent EPA correspondence, Great River Energy has not been able to fully investigate the ash mitigation feasibility. We have, however, contacted the developer of the technology, Headwaters Resources. Headwaters has not conducted any research on application of this technology to lignite. Its inadequate experience with commercial application and the lack of research on lignite means that Headwaters is unable to provide any guarantee that the process can be successfully applied to treat lignite ash. Therefore, Headwaters does not recommend application of this technology at CCS. Consequently, it has not been included in the revised analysis.

Revised Cost and Emission Information

Great River Energy has updated the cost and emission information (see attachments). Most notably, Great River Energy has updated the SNCR capital cost based upon the recent revision to the IEC Cost model (Rev 3, Nov 2010). In the initial analysis, data from the 1998 cost model was used and was escalated to 2006 dollars. In order to remain consistent with other BART Analyses and other cost estimates, GRE has de-escalated the 2010 SNCR cost to 2006 dollars. With respect to emission information, Great River Energy noticed that the baseline NOx emission values did not use the highest two-year period from the baseline due to formatting error. This minor error was corrected.

Proposed NOx Optimization Study

Great River Energy recognizes the value of reducing emissions and supports NDDH's goal of lowering emissions, as demonstrated by our willingness to install emissions reduction technology (i.e., LNB3/SOFA "Option 2") well in advance of any regulatory requirement. In addition to these existing reductions, Great River Energy will commit to an evaluation and testing of NOx emissions to determine what emission reductions can now be achieved utilizing the novel DryFining™, multi-pollutant control technology.

As you are well aware, Great River Energy voluntarily installed DryFining as an innovative patented technology. The development of the DryFining coal drying technology has taken over ten years. The system provides a means of beneficiating low-rank feedstock in a manner that results in more efficient power plant operation and reduced emissions. During its development, Great River Energy believed that the DryFining system would provide additional NOx reductions. However, with no operating experience, GRE could not predict with certainty NOx emissions reductions and could not include them as part of the Final BART Analysis, which was submitted to NDDH in late 2007. In December 2009, the $285 million DryFining system was placed in service.

Throughout 2010 and 2011, Great River Energy has continued to modify and finalize the design of this new technology. DryFining design changes are now final. The NOx, SO_2 and mercury emissions have been lowered. As one example, Unit 2's 2011 year-to-date NOx emissions are 0.146 lbs/mmBtu. This represents a 28% reduction from pre-DryFining emissions. Note that CCS Unit 2 has also installed LNB/OFA Option 2 from the BART table, in advance of the BART requirements. CCS has already demonstrated it can achieve 30-day rolling average emissions below the presumptive BART limit of 0.17 lbs/mmBtu.

Not only are Unit 2's year-to-date average emissions at 0.146 lbs/mmBtu, CCS has also operated at levels below 0.14 lbs/mmBtu on a short-term basis. CCS would need to conduct additional tuning and testing to determine whether this lower level is achievable on a 30-day rolling average basis.

To determine additional and achievable emissions reductions utilizing Option 2 and DryFining on Unit 2, Great River Energy proposes to complete a NOx optimization study. The scope of NOx optimization will include a comprehensive evaluation of NOx emissions and controls. The details of the testing program will be further determined as system experts and consultants are able to review and make recommendations for a testing protocol. The DryFining process is currently removing 8.5% of the feedstock moisture with a long term goal of 12% moisture removal. Great River Energy expects additional reductions as a result of the change in feedstock moisture. Additional testing is likely to include such things as boiler tuning and adjustments such as excessive air levels, an evaluation of computerized boiler optimization system benefits with DryFining, and burner, nozzle and SOFA designs associated with DryFining.

The preliminary timeline for testing is as follows:

- Develop testing protocol – 2011
- Testing NOx emissions at 12% moisture removal – 2011
- Engineering evaluation – 2012
- Purchase, install and calibrate carbon monoxide monitor – 2012
- Install additional thermocouples – 2013
- Perform NOx testing – 2012-2014
- Final report – December 2014

Progress reports will be communicated to the NDDH and a final written report will be prepared and delivered no later than December 2014. Based on the results of this testing and evaluation, CCS will commit to an achievable NOx emission limit that is lower than the presumptive BART value of 0.17 lb/mmBtu that is currently in the NDDH State Implementation Plan (SIP).

In summary, Great River Energy has revised the cost and emission tables to demonstrate SNCR is not cost effective. If EPA moves forward by requiring SNCR, Great River Energy is very concerned about the technical feasibility of the ash mitigation technology and, in fact, the technology developer does not guarantee or recommend the application of this technology at CCS. Therefore, as another demonstration of our commitment to emission reductions and improvement to regional haze, Great River Energy offers to complete a NOx optimization study. If these NOx reductions are incorporated into the BART analysis, it would further demonstrate that SNCR is not cost effective. We would appreciate any questions or comments that you may have on the revised analysis and proposed NOx optimization study.

GRE believes this approach is appropriately within the NDDH's authority. We request that NDDH take action to remove CCS from a proposed FIP and include this approach in the North Dakota SIP.

Please contact me if you have any questions (763-445-5212).

Sincerely,

GREAT RIVER ENERGY

for Deber Nelson

Mary Jo Roth
Manager, Environmental Services

Attachments

c: Tom Bachman, NDDH
Deb Nelson, GRE
Diane Stockdill, GRE

Great River Energy Coal Creek
BART Emission Control Cost Analysis

Table A-1a: Cost Summary

PM/PM_{10} Control Cost Summary

Baseline 0.030 lb/MMBtu

Case	Control Technology	Controlled Emissions lb/MMBtu	Control Eff %	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	PM Polishing WESP	0.015	50%	388.7	1	387.1	$7,232,000	$1,919,536	$4,959	D	NA-Base	A-4
2	PM Baghouse	0.015	50%	388.7	--	387.1	$37,370,845	$7,674,855	$19,829	I	NA	A-5
3	Dry ElectroStatic Precipitator (ESP)	0.015	50%	388.7	--	387.1	$38,510,903	$10,061,861	$25,996	I	NA	A-6

SO_2 Control Cost Summary

Baseline 2.12 lb/MMBtu

Case	Control Technology	Designed Emissions lb/MMBtu	Control Eff %	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Operating Cost MM$/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	Scrubber Replacement	0.042	98%	1097.1	3	16237.0	$196.52	$29.81	$1,836	D	$8,354	A-7
2	Scrubber Mod. + Coal Dryer	0.128	94%	3318.8	2	14015.3	$74.02	$11.25	$803	D	$281	A-8
3	Spray Dry Baghouse	0.212	90%	5485.7	--	11848.5	$178.98	$28.97	$2,445	I	NA	A-9
4	Existing Scrubber + Coal Dryer	0.358	83%	9287.2	1	8046.9	$69.00	$9.57	$1,189	D	NA-Base	A-10
5	DSI Baghouse	0.635	70%	16457.0	--	877.2	$48.75	$12.54	$14,298	I	NA	A-11

NO_x Control Cost Summary

Baseline 0.22 lb/MMBtu

Case	Control Technology	Designed Emissions lb/MMBtu	Control Eff %	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Operating Cost MM$/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	Low Temperature Oxidation (LoTOx)	0.022	90%	557	5	5015.1	$44.32	$58.21	$11,608	D	$24,061	A-12
2	Selective Catalytic Reduction (SCR) w/Reheat	0.044	80%	1114	4	4457.9	$70.44	$44.81	$10,051	D	$21,474	A-13 and A-14
3	Selective Non-Catalytic Reduction (SNCR)	0.110	50%	2786	3	2786.2	$12.72	$8.91	$3,198	D	$8,181	A-15
4	SOFA/LNB #2	0.151	32%	3799	2	1773.0	$4.91	$0.62	$350	D	$557	A-16
5	SOFA/LNB #1	0.171	23%	4306	1	1266.4	$2.63	$0.34	$267	D	NA-Base	A-17

[1] Control Technology Classification- D=Dominant, I=Inferior. Only dominant costs are used to calculate incremental cost effectiveness.

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering Chemical Plant Cost Index**	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32° F		
Expected Utiliztion Rate	100%		Temperature	330	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,612	Hours	Moisture Content	15.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm	Inflation Adj	1.19
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330° F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330° F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation		6019	80.0%	0.22		1998	40,951,514
Purchased Equipment (A1)							2005	48,826,805
Purchased Equipment Total (B)	0%	of control device cost (A)					SCR Only	**48,826,805**
Installation - Standard Costs	15%	of purchased equip cost (B)					SCR Only	8,788,825
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC							SCR + Reheat	**70,440,281**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					SCR + Reheat	38,808,410
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					SCR + Reheat	5,998,573
Total Annual Cost (Annualized Capital Cost + Operating Cost)							SCR + Reheat	**44,806,984**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	180.2	775.8				775.8	-	NA
Total Particulates	181.1	779.7				779.7	-	NA
Nitrous Oxides (NOx)	1,294.2	5,572.4	80%			1114.5	4,457.9	10,051
Sulfur Dioxide (SO_2)	4,025.8	17,334.1				17334.1	-	NA

Notes & Assumptions

1
2 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2
3 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2
4 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.36 -2.43
5 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.32 - 2.35
6 SCR Catalyst Volume per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.18 - 2.24
7 SCR Reactor Size per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.25 - 2.31
8 SCR Catalyst Replacement per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.50 - 2.53
9 SCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.48
10 SCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.46
Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values
11 approaching the BART economic feasibility values for presumptive BART.
12 Reheat cost based on 180 F temperature from scrubber exhaust
13 Process, emissions and cost data listed above is for one unit.
For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) (1)		
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC		**48,826,805**
Instrumentation	10% of control device cost (A)	NA
ND Sales Taxes	0.0% of control device cost (A)	NA
Freight	5% of control device cost (A)	NA
Purchased Equipment Total (A)		**48,826,805**
Indirect Installation		
General Facilities	5% of purchased equip cost (A)	2,441,340
Engineerin & Home Office	10% of purchased equip cost (A)	4,882,681
Process Contingency	5% of purchased equip cost (A)	2,441,340
Total Indirect Installation Costs (B)	20% of purchased equip cost (A)	**9,765,361**
Project Contingeny (C)	15% of (A + B)	**8,788,825**
Total Plant Cost D	A + B + C	**67,380,991**
Allowance for Funds During Construction (E)	0 for SNCR	**0**
Royalty Allowance (F)	0 for SNCR	**0**
Pre Production Costs (G)	2% of (D+E))	**1,347,620**
Inventory Capital	Reagent Vol * $/gal	**48,174**
Intial Catalyst and Chemicals	0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC	D + E + F + G +H + I	**68,776,786**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**NA**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Total	1.50 % of Total Capital Investment	1,031,652
Maintenance Materials	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.05 $/kwh, 5,180 kW-hr, 8611.575 hr/yr, 100% utilization	2,258,130
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
SW Disposal	5.00 $/ton, 47 ton/hr, 8611.575 hr/yr, 100% utilization	2,023,720
NA	NA	-
NA	NA	-
Lost Ash Sales	5.00 $/ton, 47 ton/hr, 8611.575 hr/yr, 100% utilization	2,023,720
NA	NA	-
NA	NA	-
Ammonia	0.92 $/lb, 1,420 lb/hr, 8611.575 hr/yr, 100% utilization	11,246,699
NA	NA	-
SCR Catalyst	500.00 $/ft3, 0 ft3, 8611.575 hr/yr, 100% utilization	1,394,223
NA	NA	-
Total Annual Direct Operating Costs		**19,978,143**
Indirect Operating Costs		
Overhead	NA of total labor and material costs	NA
Administration (2% total capital costs)	NA of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA of total capital costs (TCI)	NA
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	5,755,195
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**5,755,195**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**25,733,339**

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst				
Equipment Life	24,000	hours		
FCW	0.3157			
Rep part cost per unit	500	$/ft^3	# of Layers	12
Replacement Factor	12	.ayers replaced per year =		1
Amount Required	8,834	ft^3		
Catalyst Cost	4,416,933			
Y catalyst life factor	3	Years		
Annualized Cost	**1,394,223**			

SCR Capital Cost per EPRI Method			**40,951,514**				
Duty	6,019	MMBtu/hr	Catalyst Area	2,904	ft^2	361	*f*(h SCR)
Q flue gas	2,787,396	acfm	Rx Area	3,339		-24	*f*(h NH_3)
NOx Cont Eff	80%	(as faction)	Rx Height	57.8	ft	-728	*f*(h New) new= -728, Retrofit = 0
NOx in	0.22	lb/MMBtu	n layer	12	layers	Y	Bypass? Y or N
Ammina Slip	2	ppm	h layer	13.2	ft	127	*f*(h Bypass)
Fuel Sulfur	0.67	wt % (as %)	n total	13	layers	25,441,531	*f*(vol catalyst)
Temperature	330	Deg F	h SCR	90	ft		*f*(h SCR)
Catalyst Volume	**106,006**	ft^3	New/Retrofit	N	N or R		

Electrical Use				
Duty	6,019	MMBtu/hr		kW
NOx Cont Eff	80%	(as faction)	Power	5,179.7
NOx in	0.22	lb/MMBtu		
n catalyst layers	13	layers		
Press drop catalyst	1	in H_2O per layer		
Press drop duct	3	in H_2O		
Total				5179.7

Reagent Use & Other Operating Costs			Ammonia Use			
NOx in	0.22	lb/MMBtu	412	lb/hr Neat		
Efficiency	80%		29%	solution	56.0	lb/ft^3 Density
Duty	6,019	MMBtu/hr	1420	lb/hr	189.6	gal/hr
		Volume 14 day inventory	63,719	gal	$48,174	Inventory Cost

Operating Cost Calculations — **Annual hours of operation:** **8,612**; **Utilization Rate:** **100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8611.575 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maintenance Total	1.5	% of Total Capital Investment				1,031,652	% of Total Capital Investment
	Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	5179.7	kW-hr	44,605,471	2,258,130	$/kwh, 5,180 kW-hr, 8611.575 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8611.575 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gph	0	0	$/kgal, 0 gph, 8611.575 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 8611.575 hr/yr, 100% utilization
	WW Treat Neutralizatio	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	WW Treat Biotreateme	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	47.0	ton/hr	404,744	2,023,720	$/ton, 47 ton/hr, 8611.575 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	47.0	ton/hr	404,744	2,023,720	$/ton, 47 ton/hr, 8611.575 hr/yr, 100% utilization
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8611.575 hr/yr, 100% utilization
7	Ammonia	0.92	$/lb	1420	lb/hr	12,224,673	11,246,699	$/lb, 1,420 lb/hr, 8611.575 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8611.575 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	1,394,223	$/ft3, 0 ft3, 8611.575 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8611.575 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm — *annual use rate is in same units of measurement as the unit cost factor

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32° F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	100%		Temperature	330	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,612	Hours	Moisture Content	15.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm	Inflation Adj	1.19
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330° F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330° F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation, 1998 $'s		6019	50.0%	0.22		1998	3,627,729
Purchased Equipment (A)		[13]contingencies and installation costs included (indexed to 2006$)					2009	12,395,598
Purchased Equipment Total (B)	0%	of control device cost (A)						**12,395,598**
Installation - Standard Costs	15%	of purchased equip cost (B)						0
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**12,715,834**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,845,209
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,064,053
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**8,909,261**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180.2	775.8				775.8	-	NA
Total Particulates	181.1	779.7				779.7	-	NA
Nitrous Oxides (NOx)	1,294.2	5,572.4	50.0%			2786.2	2,786.2	3,198
Sulfur Dioxide (SO_2)	4,025.8	17,334.1				17334.1	-	NA

Notes & Assumptions

1
2 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1
3 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.19
4 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.22
5 Water use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.25
6 Additional Fuel Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.29
7 SNCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.23
8 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
9 Lignite Coal Assumptions 6,054 Btu/lb (wet) Ash 6.2% 42% moisture $10.20/ton delivered
10 Control Efficiency = % reduction needed to meet presumptive BART of 0.29 lb/MMBtu
Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values
11 approaching the BART economic feasibility values for presumptive BART.
12 Process, emissions and cost data listed above is for one unit.
For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
13 Values obtained from IECCOST Model V.3, Issued November 5, 2010. ($25.47/kW at 550,000kW)

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			**0**
Instrumentation	10%	of control device cost (A)	NA
ND Sales Taxes	0.0%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**0**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	0
Engineerin & Home Office	10%	of purchased equip cost (A)	0
Process Contingency	5%	of purchased equip cost (A)	0
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**0**
Project Contingeny (C)	15%	of (A + B)	**0**
Total Plant Cost D		A + B + C + SNCR Costs	**12,395,598**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**247,912**
Inventory Capital		Reagent Vol * $/gal	**72,324**
Intial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**12,715,834**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,715,834**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	15.00	% of Total Capital Investment	1,907,375
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 81 kW-hr, 8611.575 hr/yr, 100% utilization	35,387
NA	NA		-
Water	0.31	$/kgal, 510 gph, 8611.575 hr/yr, 100% utilization	1,360
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.00	$/ton, 47 ton/hr, 8611.575 hr/yr, 10% ash landfill	2,023,720
NA	NA		-
NA	NA		-
Lost Ash Sales	5.00	$/ton, 47 ton/hr, 8611.575 hr/yr, 10% Non-saleable	2,023,720
NA	NA		-
NA	NA		-
Urea	405.00	$/ton, 1 ton/hr, 8611.575 hr/yr, 100% utilization	1,853,646
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**7,845,209**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	1,064,053
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,064,053**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,909,261**

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	500	$/ft^3
Amount Required	12	ft^3
Packing Cost	6,300	Cost adjusted for freight & sales tax
Installation Labor	945	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	160	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.22	lb/MMBtu	kW
NSR	1.24		
Power			81.2
Total			81.2

Reagent Use & Other Operating Costs			Urea Use			
NOx in	0.22	lb/MMBtu	531	lb/hr Neat		
Efficiency	50%		50%	solution	71.0	lb/ft^3 Density 50% Solution
Duty	6,019	MMBtu/hr	1063	lb/hr	112.0	gal/hr
		Volume 14 day inventory	37,632	gal	$72,324	Inventory Cost
Water Use	510	gal/hr	Inject at 10% solution			
					10.74	wt % ash
Fuel Use	8.61	MMBtu/hr			37.30	% Coal Moisture Content
					0.73	% Coal Sulfur Content
Ash Generation	147.83	lb/hr			6,257	Btu/lb of coal

Operating Cost Calculations — **Annual hours of operation:** **8,612** — **Utilization Rate:** **100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8611.575 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maintenance Total	15	% of Total Capital Investment				1,907,375	% of Total Capital Investment
	Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	81.2	kW-hr	699,012	35,387	$/kwh, 81 kW-hr, 8611.575 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8611.575 hr/yr, 100% utilization
	Water	0.31	$/kgal	509.5	gph	4,388	1,360	$/kgal, 510 gph, 8611.575 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 8611.575 hr/yr, 100% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	WW Treat Biotreatement	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	47.0	ton/hr	404,744	2,023,720	$/ton, 47 ton/hr, 8611.575 hr/yr, 10% ash landfill
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	47.0	ton/hr	404,744	2,023,720	$/ton, 47 ton/hr, 8611.575 hr/yr, 10% Non-saleable
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8611.575 hr/yr, 100% utilization
3	Urea	405	$/ton	0.5315	ton/hr	4,577	1,853,646	$/ton, 1 ton/hr, 8611.575 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8611.575 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8611.575 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8611.575 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-16: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #2

Operating Unit: Unit 1 or 2

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32° F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,612	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330° F
			Dry Std Flow Rate	1,312,850	dscfm @ 330° F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			1,000,000
Purchased Equipment Total (B)	5%	of control device cost (A)	**1,050,000**
Installation - Standard Costs	0%	of purchased equip cost (B)	2,000,000
Installation - Site Specific Costs			NA
Installation Total			2,000,000
Total Direct Capital Cost, DC			3,050,000
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	0
Total Capital Investment (TCI) = DC + IC			**4,913,299**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	7,966
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	612,453
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**620,419**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	180.2	775.8				775.8	-	NA
Total Particulates	181.1	779.7				779.7	-	NA
Nitrous Oxides (NOx)	1,294.2	5,572.4	32%			3799.3	1,773.0	350
Sulfur Dioxide (SO_2)	4,025.8	17,334.1				17334.1	-	NA

Notes & Assumptions

1. Sept 2005 Cost Estimate from Foster Wheeler, Option 1. Assumed price listed is for one unit. Costs in spreadsheet are for one unit
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)
3. Assumed 0.1 hr/shift operatior and maintenance labor for LNB
4. Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART.
5. Process, emissions and cost data listed above is for one unit.
6. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-16: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #2

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			1,000,000
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	0%	of control device cost (A)	0
Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	50,000
Purchased Equipment Total (B)	5%		1,050,000
Installation			
Foundations & supports		of purchased equip cost (B)	0
Handling & erection		of purchased equip cost (B)	0
Electrical	10%	of purchased equip cost (B)	105,000
Piping		of purchased equip cost (B)	0
Insulation	15%	of purchased equip cost (B)	157,500
Painting		of purchased equip cost (B)	0
Installation Subtotal Standard Expenses (1)			2,000,000
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			2,000,000
Total Direct Capital Cost, DC			3,050,000
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	
Construction & field expenses	10%	of purchased equip cost (B)	
Contractor fees	0%	of purchased equip cost (B)	
Start-up	1%	of purchased equip cost (B)	
Performance test	1%	of purchased equip cost (B)	
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	0
Ozone Generator, Installed Cost			0
Total Capital Investment (TCI) = DC + IC		2010 Actual Total costs of Installation indexed to 2006 $	4,913,299
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			4,913,299
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 8611.575 hr/yr	3,983
Maintenance Materials	100%	of maintenance labor costs	3,983
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			7,966
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	4,779
Administration (2% total capital costs)	2%	of total capital costs (TCI)	98,266
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	49,133
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	49,133
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	411,142
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	612,453
Total Annual Cost (Annualized Capital Cost + Operating Cost)			620,419

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-16: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #2

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower, Scrubber	2,488,000		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	Liquid SPGR	D P ft H2O	Efficiency	Hp	kW	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5 kW/lb O_3					0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs					
Ozone Needed	1.8	lb O3/lb NOx	- lb/hr O3		
Oxygen Needed	10%	wt O2 to O3 conversion		0 lb/hr O2	0 scfh O2
LTO Cooling Water	150	gal/lb O3	0 gpm		
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf			
Circulating Water Rate	0	gpm			
Water Makeup Rate/WW Disch =		20% of circulating water rate =	0 gpm		
Scrubber Cost	10	$/scfm Gas	$0	Incremental cost per BOC. Need to increase vessel size over standard absorber.	
Ozone Generator	$350	lb O3/day	$0 Installed	Installed cost factor per BOC.	

Operating Cost Calculations — **Annual hours of operation: 8,612** — **Utilization Rate: 100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	0	$/Hr	0.1	hr/8 hr shift	108	0	$/Hr, 0.1 hr/8 hr shift, 8611.575 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	108	3,983	$/Hr, 0.1 hr/8 hr shift, 8611.575 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	3,983	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8611.575 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8611.575 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8611.575 hr/yr, 100% utilization
	WW Treat Neutralizatio	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	WW Treat Biotreateme	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8611.575 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8611.575 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8611.575 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8611.575 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8611.575 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-17: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #1

Operating Unit: Unit 1 or 2

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32° F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,612	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330° F
			Dry Std Flow Rate	1,312,850	dscfm @ 330° F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			500,000
Purchased Equipment Total (B)	5%	of control device cost (A)	**525,000**
Installation - Standard Costs	0%	of purchased equip cost (B)	2,000,000
Installation - Site Specific Costs			NA
Installation Total			2,000,000
Total Direct Capital Cost, DC			2,525,000
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	105,000
Total Capital Investment (TCI) = DC + IC			**2,630,000**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	7,966
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	330,056
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**338,022**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	180.2	775.8				775.8	-	NA
Total Particulates	181.1	779.7				779.7	-	NA
Nitrous Oxides (NOx)	1,294.2	5,572.4	23%			4305.9	1,266.4	267
Sulfur Dioxide (SO_2)	4,025.8	17,334.1				17334.1	-	NA

Notes & Assumptions

1. Sept 2005 Cost Estimate from Foster Wheeler, Option 1. Assumed price listed is for one unit. Costs in spreadsheet are for one unit
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)
3. Assumed 0.1 hr/shift operatior and maintenance labor for LNB
4. Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART.
5. Process, emissions and cost data listed above is for one unit.
6. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-17: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #1

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**500,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	0%	of control device cost (A)	0
Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	25,000
Purchased Equipment Total (B)	5%		**525,000**
Installation			
Foundations & supports		of purchased equip cost (B)	0
Handling & erection		of purchased equip cost (B)	0
Electrical		of purchased equip cost (B)	0
Piping		of purchased equip cost (B)	0
Insulation		of purchased equip cost (B)	0
Painting		of purchased equip cost (B)	0
Installation Subtotal Standard Expenses (1)			**2,000,000**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**2,000,000**
Total Direct Capital Cost, DC			**2,525,000**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	26,250
Construction & field expenses	10%	of purchased equip cost (B)	52,500
Contractor fees	0%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	5,250
Performance test	1%	of purchased equip cost (B)	5,250
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	15,750
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	**105,000**
Total Capital Investment (TCI) = DC + IC			**2,630,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**2,630,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 8611.575 hr/yr	3,983
Maintenance Materials	100%	of maintenance labor costs	3,983
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**7,966**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	4,779
Administration (2% total capital costs)	2%	of total capital costs (TCI)	52,600
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	26,300
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	26,300
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	220,077
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**330,056**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**338,022**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-17: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #1

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower, Scrubber	2,488,000		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	Liquid SPGR	D P ft H2O	Efficiency	Hp	kW	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5	kW/lb O_3				0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs					
Ozone Needed	1.8	lb O3/lb NOx	-	lb/hr O3	
Oxygen Needed	10%	wt O2 to O3 conversion	0	lb/hr O2	0 scfh O2
LTO Cooling Water	150	gal/lb O3	0	gpm	
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf			
Circulating Water Rate	0	gpm			
Water Makeup Rate/WW Disch =	20%	of circulating water rate =	0	gpm	
Scrubber Cost	10	$/scfm Gas	$0		Incremental cost per BOC. Need to increase vessel size over standard absorber.
Ozone Generator	$350	lb O3/day	$0	Installed	Installed cost factor per BOC.

Operating Cost Calculations — **Annual hours of operation: 8,612** — **Utilization Rate: 100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	0	$/Hr	0.1	hr/8 hr shift	108	0	$/Hr, 0.1 hr/8 hr shift, 8611.575 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	108	3,983	$/Hr, 0.1 hr/8 hr shift, 8611.575 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	3,983	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8611.575 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8611.575 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8611.575 hr/yr, 100% utilization
	WW Treat Neutralizatioi	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	WW Treat Biotreatemei	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8611.575 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8611.575 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8611.575 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8611.575 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8611.575 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions